### **MEMORANDUM**

TO: Robert Haynes

THROUGH: John B. Blevins

Ali Mirzakhalili, P.E.

Robert J. Taggart

FROM: Ravi Rangan, P.E.

SUBJECT: Response Document Developed by the Air Quality Management (AQM)

Section for the Public Hearing Held on August 18, 2004 for the Title V - Part

3 Draft Permit for The Premcor Refining Group, Inc.

DATE: September 29, 2004

The Air Quality Management (AQM) Section of the Department of Natural Resources and Environmental Control has completed its review of the transcript of the public hearing held on August 18, 2004 to receive comment on The Premcor Refining Group, Inc.'s (Premcor's) Title V – Part 3 draft permit.

Part 3 of Premcor's Title V application addresses the company's power plant and repowering project, located at the Delaware City Refinery and includes the gasifiers, combustion turbines, a flare, power plant boilers, a cooling tower and other components. The attached response document provides AQM's responses to the written comments received prior to the hearing from the following entities:

- Premcor;
- The Mid-Atlantic Environmental Law Center (MAELC) on behalf of the Sierra Club; and
- United States Environmental Protection Agency (EPA), Region III

It also provides responses to questions raised during the hearing by the following entities:

- The Mid-Atlantic Environmental Law Center (MAELC) on behalf of the Sierra Club;
- The Sierra Club; and
- Green Delaware

Your patience in awaiting receipt of these responses is appreciated. I hope this information will assist you in reviewing the issues and making your recommendation to the Secretary.

### **Responses to Public Comments**

# Title V (Part 3) Operating Permit Delaware City Power Plant / Premcor Refinery

September 2004

### Prepared for

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A.	Comment Letter from Premcor, dated June 14, 2004		
B.	Comment Letter / Request for Public Hearing from MAELC, dated June 10, 2004		
C.	Comments from EPA, via electronic mail dated June 17, 2004		
D.	Testimony from MAELC at the Public Hearing, dated August 18, 2004		

### 1.0 General Comments from Premcor

<u>Comment</u>: Comment 1: Clarification of Supplemental Reporting Requirement.

Response: In this comment, the facility has requested that supplemental reporting of excess emissions in instances that do not pose an imminent and substantial danger to public health be allowed via fax or electronic mail as an alternative to telephone reporting. DNREC disagrees. Condition 3 c. 2. i. B. has been developed as a boiler plate condition that is applicable to all Title V sources in the state. However, DNREC notes that the draft permit contains an incorrect regulatory citation, i.e., Regulation No. 30, Section 6(a)(3)(C)(iii)(cc). The correct citation should be Regulation No. 30, Section 6(a)(3)(C)(iii)(bb). Therefore, DNREC has made the correction to the above referenced regulatory citation, but has left the boiler plate condition intact.

<u>Comment</u>: Comment 2: Clarification of the term "Stack Test Based Emissions Factor"

Response: In this comment, the facility refers to the term "Stack Test Based Emissions Factor" that is required to be used in determining compliance with certain emission limits in the permit, e.g., PM-10 emission limit for the boilers and the combined cycle units (CCUs). This emissions factor is derived from the stack test performed for the unit and pollutant in question, and subsequently used to calculate actual emissions from the unit using actual operating data such as fuel use and hours of operation. The facility has requested that this term be defined to clarify that the factor is derived once from the most recent stack test and that a stack test is not required each time emissions calculations are performed. DNREC concurs with the facility that the purpose of this emissions factor is for use in both current and future compliance determination, and that a stack test is not required each time compliance calculations have to be performed. However, DNREC believes that the emissions factor used in compliance demonstration must be representative of current operating conditions of the unit. For this reason, DNREC is requiring that the emissions factor be updated over time and therefore be derived from stack tests that are no more than five years old. The following definition is included in Condition 2.e of the proposed permit.

"Stack Test Based Emissions Factor" means an emissions factor derived from the results of the most recent compliance stack test performed within the last five (5) years for the unit in question.

Note that the five-year period for stack testing coincides with the five-year duration of the Title V permit. This means that the facility will be required to perform a stack test at least once during each five-year permit term.

Comment: Comment 3: Condition 5 Compliance Schedule

Response: In this comment, the facility refers to the forms AQM-1001Z submitted with Revision 8 of the Title V permit application in February 2004 presenting the proposed compliance plans for Boilers 1, 2 and 3, and requests that a compliance plan be included

in the permit. As presented, the Forms AQM-1001Z list PM-10 non-compliance for all three boilers, TSP non-compliance for Boilers 1 and 3, and VOC non-compliance for Boiler 2. The forms propose a compliance date of June 25, 2004 for Boiler 2 and December 30, 2006 for Boilers 1 and 3. DNREC does not agree with this comment because the forms AQM-1001Z submitted with the application are either not valid or are incomplete for the following reasons.

The compliance date for Boiler 2 of June 25, 2004 has already passed. This boiler is currently operating under its modified configuration and its performance tests have been completed. DNREC is awaiting the submittal of the results of these performance tests. Currently, there is no reason to believe that Boiler 2 will not meet its emission limits. Therefore, a compliance plan is not necessary for this unit.

The listed non-compliance for Boilers 1 and 3 include emission limits that are only applicable when No. 6 fuel oil is combusted. Under the facility's Consent Decree, No. 6 oil is no longer combusted in any of the boilers. Therefore, these emission limits do not apply. Consequently, no compliance plan is necessary for these limits.

With respect to the only remaining emissions limit listed in forms AQM-1001Z, i.e., the PM-10 emission limit of 0.005 lb/MMBtu when combusting gaseous fuel (refinery fuel gas, natural gas or synthesis gas), DNREC is aware that the facility has conducted stack tests for Boilers 1 and 3 and that individual runs during these tests showed compliance (e.g.: Run # 3 of the stack test conducted in October 2001 showed PM-10 emissions of 4.56 E-03 lb/mmBtu) while other runs showed marginal non-compliance compliance with the limit (e.g.: Run # 2 of the same stack test showed PM-10 emissions of 5.37 E-03 lb/mmBtu). DNREC also notes that the facility has not proposed any additional controls in its form AQM-1001Z as being required to bring the units into compliance. Instead, the AQM-1001Z form indicates the facility intends seeking a change in the permitted emission standard. It is DNREC's opinion that the marginal non-compliance can be overcome by means of minor adjustments in operating parameters and by implementing good engineering operating practices to minimize emissions. Furthermore, DNREC finds it to be a reasonable conclusion that these two boilers are capable of meeting the emission limit of 0.005 lb/MMBtu by implementing good air pollution control practices. Therefore, DNREC does not see any reason why an extended compliance schedule of more than two years, i.e., until December 30, 2006, is necessary. Instead, DNREC is requiring additional testing to be performed to demonstrate compliance and incorporating such additional testing in the proposed permit. If Boilers 1 and 3 continue to show non-compliance, DNREC will view such non-compliance as a matter for possible enforcement action.

With respect to the facility's general requirement to operate the facility in compliance, Condition 2.b of this Title V permit clearly states that the facility must stay in continuous compliance with the currently applicable requirements, and meet in a timely manner any applicable requirements that become effective during the term of the permit.

<u>Comment</u>: Comment 4: Merging of the Quarterly Reporting and the Semiannual Deviation Reporting Requirements

Response: In this comment, the facility has requested that routine quarterly emissions reports and the semi-annual monitoring and deviation reports be combined into a single semi-annual reporting requirement to avoid redundancies, and that the backup raw data supporting these reports be maintained on site instead of being included in the report. The facility has also commented that some of the data collection requirements are not necessary for compliance demonstration or are redundant with other provisions of the permit, and therefore should be removed. DNREC does not agree with this comment and does not intend to change the reporting or the data collection requirements of the permit. DNREC is cognizant of the facts that the Repowering Project is still evolving, operation has been inconsistent and sporadic. Quarterly reports have enabled DNREC to maintain an up to date status of the project. Furthermore, DNREC believes that each of these reports, and the associated data collection and documentation, serve a unique purpose in the overall demonstration of continuous compliance with the permit terms and conditions, and are therefore essential elements of the Title V permit.

#### Comment: Comment 5: Permit Shield

Response: In this comment, the facility has requested that a permit shield be included in the permit stating that compliance with the terms and conditions of the permit shall constitute compliance with any applicable regulations specifically identified in the permit as of the day of permit issuance. While DNREC is not opposed to this request, given that the Title V permit is being issued in three parts (owing to the complexity of this facility), it is not feasible to include a permit shield at the present time. Therefore, DNREC is currently denying a permit shield. Note that Part 1 of the Title V permit also did not include a permit shield. DNREC envisions that when all parts of the permit have been completed, and the permit is combined into a single permit document, a permit shield would then be feasible. At such time, DNREC will be in a position to consider an application by the facility to grant a permit shield.

### 2.0 Specific Comments from Premcor

<u>Comment</u>: Comment 1: Permit "cover page": The correct plant location is 4550 Wrangle Hill Road.

<u>Response</u>: The proposed permit and review memorandum reflect the address as 4550 Wrangle Hill Road, Delaware City, Delaware 19706.

Comment: Comment 2: Table 2 Emission Points, Units and Identification of Applicable Requirements [p. 5]: Consistent with DNREC's Review Memorandum p.17, we understand that the description of the source design capacities given in the "Source Description" for each emission unit do not constitute enforceable conditions of the permit. Premcor requests that a footnote be added at the bottom of the table to clarify this issue. Also, please note that the three components included in Emissions Unit 83 are mis-referenced; the amine acid gas removal system and syngas flare are both associated with Emissions Unit 82, while the evaporative cooler is associated with Emission Unit 50. The same corrections should also appear on Page 6, under the permit description for APC-97/0504, and page 36.

Response: While preparing the draft permit, DNREC had agreed to not include the source design capacities as enforceable permit conditions, and had acknowledged this fact in the review memorandum. DNREC disagrees with Premcor's interpretation regarding the enforceability of the source's design capacities given in the "source description". DNREC does not feel there was (or is) a need to indicate it in a footnote in the permit. Note, however, that DNREC has been evaluating whether boiler design capacities should be included as permit conditions. Based on this evaluation, and comments received from the Mid-Atlantic Environmental Law Center, the Sierra Club and Green Delaware, on the draft permit, DNREC has decided to include the design capacity of Boiler 4 as a permit condition (see further discussions below in this document).

DNREC agrees that the amine acid gas removal system and the syngas flare are a part of Emissions Unit 82 (EU 82). Listing them as EU 83 in the draft permit was inadvertent. The proposed permit and the review memorandum reflect these units as part of EU 82. The evaporative cooler will be listed as Emission Unit 50 (EU 50) in the proposed permit.

<u>Comment</u>: Comment 3: Item 2.1 [10]: should be revised to expire five years from the date of permit issuance.

Response: The expiration date for Part 3 of the Title V permit was changed from November 13, 2006 to November 13, 2008 based on Motiva's comments on the prenotification draft permit. The 2006 expiration date was selected to coincide with the expiration of the Part 1 permit, which was issued in 2001. DNREC is not opposed to an expiration date of five (5) years for Part 3 and has reflected a five year term in the proposed permit. However, it is DNREC's intent to merge all parts of this permit into a single permit document at a future permit renewal date, at which time the entire refinery

will have a single Title V permit expiration date. To accomplish this, a future term of one or more parts of this permit will have to be less than five years.

<u>Comment</u>: Comment 4: Condition 2.e [9]: add "or the version referenced in the specific permit condition or the most recent update of this reference document" at the end of definition 2 for "AP-42."

<u>Response</u>: DNREC has updated the definition of "AP-42" in the permit as follows to reflect the most recent editions and updates.

"AP-42" means the Compilation Of Air Pollutant Emission Factors, Fifth Edition, AP-42, dated January 15, 1995, as amended with Supplements "A" dated February 1996, "B" dated November 1996, "C" dated November 1997, "D" dated August 1998, "E" dated September 1999, and "F" dated September 2000 and the December 2001 update, the December 2002 update and the December 2003 update.

<u>Comment</u>: Comment 5: Condition 3.c.2.i [16]: add in front of this general reporting requirement "The Company shall submit the initial semi-annual monitoring report no later than six (6) months after the issuance of this permit. For all subsequent semi-annual reports …"

Response: DNREC is denying Premcor's request. DNREC notes that between the time the draft Part 3 permit was made available to Premcor (i.e., May 7, 2004) to the time the permit is expected to be issued as final, more than 6 months will have elapsed. Therefore, Premcor has had ample time to develop the reports required by Condition 3.c.2.i. in the draft Part 3 permit.

<u>Comment</u>: Comment 6: Condition 3 Tbl 1.a.2.i.A and B [19]: Add natural gas as one of the fuels used in Boiler 4. Natural gas has always been mixed with refinery fuel gas prior to being introduced into all four boilers, yet natural gas is only mentioned as a fuel for Boilers 1, 2 and 3. This appears to be an oversight in the permitting of this boiler since the Boiler 4 permit has not been updated since 1993. Consequently, to be consistent for all four boilers we are asking to recognize natural gas as a fuel to Boiler 4 in this permit. Also, add Boiler 4 to the list of units authorized to burn oil during a curtailment.

Response: DNREC agrees that allowing the combustion of natural gas in Boiler 4 is reasonable and has included it in the proposed permit. Natural gas is a clean burning fuel similar to refinery fuel gas (RFG) and will not result in emissions higher than those resulting from RFG combustion. DNREC also understands the need for an alternate fuel during periods of natural gas curtailment, which typically have the potential to occur during winter months, and is allowing the combustion of low-sulfur No. 2 fuel oil (low-sulfur liquid fuel, or LSLF) during such periods. The use of LSLF in Boiler 4 will be subject to the same requirements as in Boilers 1, 2 and 3, including the sulfur content requirement (0.05 weight percent sulfur or less) and the semi-annual reporting that includes the following: (1) number of hours on LSLF, (2) quantity of LSLF, (3) sulfur

content of LSLF, and (4) specification sheet for each batch of LSLF. Note that the use of No. 6 fuel oil is no longer allowed at the facility under any circumstance.

<u>Comment</u>: Comment 7: Condition 3 Tbl 1.a.2.v.A [19]: Consistent with the request made by Mr. Michael Gritz to Mr. Robert Taggart in a letter dated 12/11/03 to allow sufficient operating experience prior to proposing revised unit emission limits, Premcor requests that the application addressing this issue be due 3/31/05.

Response: The Regulation No. 2 permit that approved the modification of Boiler 2, i.e., APC-97/0289-Construction (Amendment 5) (RACT), dated October 25, 2002, specified the combined emission limits for Boilers 1, 2 and 3 and the Combined Cycle Units (CCUs). This Regulation No. 2 permit also required the facility to submit individual emission limits for Boilers 1 and 3 and the CCUs at least six (6) months before the modification of Boiler 2 is completed, i.e., latest by December 25, 2003. However, because DNREC recognizes that there have been startup problems relating to sustained and reliable operation of the repowering project, and agrees that actual operational history is necessary to have any confidence in the achievability of the individual emission limits for these units, DNREC finds it reasonable to await operating data for a period of about a year. Given that the Boilers 1, 2 and 3 are now operational on gaseous fuels (i.e., RFG / syngas / natural gas), DNREC does not foresee a problem in allowing the facility some post-modification operating experience. The proposed Title V (Part 3) permit reflects a new deadline of March 31, 2005 for the submittal of individual emission limits for Boilers 1 and 3 and the CCUs. No later than March 31, 2005, the facility must submit a complete permit application proposing these individual emission limits that quantify the emissions reductions attributable to the increased utilization of Boiler 2. In granting this extension, DNREC notes that the current Regulation No. 2 permits for Boilers 1 and 3 (i.e., APC-97/0288-Construction and APC-97/0290-Construction) will expire on December 31, 2004. However, this Title V permit is expected be in effect by that time, and furthermore, it will be modified upon receipt of the new individual emission limits.

<u>Comment</u>: Comment 8: Condition 3 Tbl 1.a.2.ii.d [19]: We request a revision that says "The rates may be adjusted based on the experience of the company with these controls, consistent with minimizing emissions and good engineering practices."

<u>Response</u>: DNREC agrees. The proposed permit reflects the change. The steam injection and flue gas recirculation rates for the boilers may be adjusted to minimize emissions and should generally stay within the ranges specified by the manufacturer.

<u>Comment</u>: Comment 9: Condition 3 Tbl 1.a.2.i.E [20]: Add the phrase "Upon completion of the modifications to Boiler 2, ..."

<u>Response</u>: DNREC agrees. The proposed permit reflects this change. This condition only applies to Boiler 2 after its modification is completed.

<u>Comment</u>: Comment 10: Condition 3 Tbl 1.a.2.vi [22]: Delete this requirement since this is a consent decree limit and not a permanent limit for the Title V permit. Additionally,

we note that the fuel oil supply piping to all boilers has been removed, so there is no physical means to burn fuel oil in Boilers 1, 2, 3 and 4. Should the need to burn oil during a curtailment period arise, the oil piping would need to be reinstalled.

Response: DNREC does not agree that this requirement should be removed. The most recent Regulation No. 2 permits for Boilers 1, 2, 3 and 4 specify emission limits for combustion of No. 6 fuel oil. The Title V permit is the vehicle that DNREC is using to specify that combustion of No. 6 fuel oil is no longer allowed in these boilers. Therefore, these emission limits are no longer applicable. This requirement also clarifies that only the combustion of low-sulfur liquid fuel, i.e., No. 2 fuel oil, is allowed during periods when natural gas supply is curtailed.

Comment: Comment 11: Condition 3 Tbl 1.a.3.iii.a [23]: Delete "CCUs, duct burners."

Response: Given that the PM-10 and TSP emission limits are specified as a combined limit for the Boilers 1, 2 and 3 and the CCUs, the compliance methodology must also specify each of these units. For this reason, DNREC does not agree that the CCUs and the duct burners should be removed from this paragraph. DNREC realizes that there is a redundancy in this permit, wherein some of the emission limits and the associated compliance, monitoring, recordkeeping and reporting requirements are listed first for the boilers and then repeated again for the CCUs. This is because the boilers and the CCUs are listed separately in the Title V permit under their own Emission Unit ID's, and furthermore, the Regulation No. 2 permits for the boilers and the CCUs specify these limits independently of each other.

<u>Comment</u>: Comment 12: Condition 3 Tbl 1.a.5.i.E [26]: All of the boilers have the same NOx emissions limit of 0.25 lb/MMBtu.

Response: Given that DNREC has agreed to allow natural gas combustion in Boiler 4 and also allow combustion of LSLF during periods of natural gas curtailment, the NOx limit of 0.25 lb/MMBtu applies to Boiler 4. Therefore, all four boilers are subject to the same emissions limit under Regulation No. 12, Section 3.2(a). Note, however, that this limit only applies when LSLF is being fired in the boilers. The proposed permit reflects the 0.25 lb/MMBtu limit when firing oil.

<u>Comment</u>: Comment 13: Condition 3 Tbl 1.c.1.i.B [37]: Add the phrase "during periods of process upset and malfunction" after the word "flaring" in line 4, per previous agreement with permit staff.

Response: The referenced permit condition allows the flaring of syngas for up to 800 hours per year. DNREC agrees that this 800-hour limit only applies during periods of process upset and malfunction, and does not apply to periods of startup and shutdown. The language in the proposed permit has been revised to reflect this change. The revised language also clarifies that this limit only applies to flaring of clean syngas and not to raw syngas. It should be noted, however, that the emission limits specified in the permit (709 tons per rolling twelve months) for this flare include emissions resulting from all flaring

events, including clean and raw syngas flaring, as well as flaring during startup/shutdown and process upset/malfunction scenarios.

<u>Comment</u>: Comment 14: Condition 3 Tbl 1.c.2.i.B [38]: Delete this condition as it is not in the current permit and the cooling tower is not an industrial process unit.

<u>Response</u>: DNREC does not agree that this condition should be removed. The cooling tower qualifies as an industrial process operation as defined in Delaware Regulation No. 1, and is therefore subject to Regulation No. 5, Section 2.1.

<u>Comment</u>: Comment 15: Condition 3 Tbl 1.c.3.iv.B [39]: This condition can be dropped as the obligation has been completed.

<u>Response</u>: DNREC agrees that this permit condition requiring the analysis raw syngas by September 30, 2003 has been met, and has removed it from the proposed permit.

<u>Comment</u>: Comment 16: Condition 3 Tbl 1.c.4.v.A [40] and c.5.v.A [41]: This condition related to maintaining records of the amount of natural gas combusted for the pilot flame and amount of raw and clean syngas flared should be deleted, since it is not an existing permit requirement. There is no means to measure this flow; by design, pilot flames (and fuel gas use) are in continuous use when the flare is operational.

Response: The purpose of natural gas combustion in the flare is to maintain the pilot flame so that it is continuously available for syngas flaring needs. Given that the total emissions from the flare include the emissions from natural gas combustion, the purpose of requiring records of the amount of natural gas combusted was to facilitate calculation of that component of the emissions. DNREC agrees that there is currently no flow meter installed for monitoring the amount of natural gas used in the flare. Furthermore, DNREC understands that natural gas combustion constitutes only a small fraction of the total flare emissions. For example, the NOx emissions from natural gas combustion are approximately 0.5 tons per year compared to the total permitted level of 28 tons per year from the flare. Similarly, the SO<sub>2</sub> and CO emissions from natural gas combustion are approximately 0.003 and 0.10 tons per year, respectively, compared to the permitted levels of 709 and 1,117 tons per year, respectively, from the flare. Therefore, DNREC has removed the requirement to monitor and record natural gas flow to the flare.

With respect to the amounts of raw and clean syngas flared, DNREC does not agree that this condition should be removed. The production rates of raw and clean syngas are required to be monitored and, therefore, the documentation of the amounts of raw and clean syngas flared should be a simple exercise. Furthermore, given that syngas flaring constitutes the majority of the flare emissions, documentation of these flow rates is necessary for accurate emissions calculations.

<u>Comment</u>: Comment 17: Condition 3 Tbl 1.d.1.iii.D [42] and 3.d.1.ii.D and 3.d.1.iv.B [43]: The requirements related to compliance with 40 CFR 60 Subpart J should all be

deleted based on the decision of the US Court of Appeals for the Third Circuit holding that this regulation does not apply to these units.

Response: These permit conditions pertain to the monitoring of H<sub>2</sub>S and sulfur contents of syngas prior to it being combusted. The H<sub>2</sub>S monitoring requirement stems from 40 CFR 60 Subpart J (Section 60.104(a)(1)) while the monitoring of sulfur content is a Regulation No. 2 permit condition. DNREC acknowledges that the H<sub>2</sub>S monitoring and reporting requirement can be removed from the permit if 40 CFR 60.104(a)(1) is indeed not applicable. However, in order to accomplish this, the facility must submit a complete permit application requesting this change along with the Administrator's concurrence with the referenced court decision that this regulation is not applicable. Upon receipt of this application, DNREC will initiate an amendment process to revise the permit.

DNREC does not agree that the requirement to monitor the sulfur content of syngas can be removed because this is a Regulation No. 2 permit condition.

<u>Comment</u>: Comment 18: Condition 3 Tbl 1.d.7.i.B [51]: Delete ... not a requirement applicable to this unit.

Response: DNREC agrees that this permit condition limiting  $H_2SO_4$  emissions only applies to Boiler 2 and has removed it from this section of the proposed permit.

<u>Comment</u>: Comment 19: Condition 3 Tbl 1.e.3.iv [54]: The obligations related to opacity observations should be limited to those sources which do not have stack opacity monitors.

<u>Response</u>: DNREC agrees. However, this section becomes applicable during periods when the COMS is disabled or is not operating properly.

<u>Comment</u>: Comment 20: Lastly, we request that the staff review memorandum be amended consistent with the comments presented here related to the permit conditions.

<u>Response</u>: DNREC agrees. The review memorandum has been revised, as necessary, to reflect all of DNREC's responses presented in this document.

## 3.0 General Comments from Mid-Atlantic Environmental Law Center (MAELC)/Sierra Club

<u>Comment</u>: Comment 1: The Title V permit does not provide an adequate compliance schedule.

Response: In this comment, the Mid-Atlantic Environmental Law Center (MAELC) refers to the various reportable releases that have occurred at the facility in 2004 and previous years. The MAELC also refers to the numerous notices of violations (NOVs) and enforcement actions that DNREC has issued against the facility. Finally, the MAELC refers to the facility's consent decree and an ongoing lawsuit that DNREC filed in connection with a fatal explosion and fire at the facility in 2001. Based on these, the MAELC concludes that the facility needs a compliance schedule sufficient to bring it into compliance with all the emission requirements.

DNREC acknowledges the various reportable releases that have occurred at the facility as listed in Exhibit A of the MAELC's comment letter. Under Federal Emergency Planning and Community Right to Know Act (EPCRA Section 304) and the State of Delaware Regulation 6028 (7 Del. C., Section 6028), those releases that are not specified in a facility's operating permit and that exceed certain thresholds are required to be reported. These thresholds, called Delaware Reportable Quantities (DRQs), are listed in Section 3 of Regulation 6028. The reporting of the releases by the facility was in compliance with the regulation.

While required to be reported, these releases are not necessarily a matter requiring a compliance plan or a compliance schedule. When reporting these releases, the facility is required to clearly document the facts and circumstances leading to the environmental release and the measures proposed to prevent such a discharge from occurring in the future. The purpose of this reporting is to not only make DNREC and the public aware of the releases, but also to initiate corrective action measures immediately.

During the public hearing held on August 18, 2004, the MAELC commented that under 40 CFR 70.6(c) and Delaware Regulation No. 30, Section 6(c)(3), it is mandatory that a facility's Title V permit contain a compliance schedule consisting of the following three parts.

- (1) For applicable requirements with which the source is in compliance, a statement that the source will continue to comply with such requirements;
- (2) For applicable requirements that will become effective during the permit term, a statement that the source will meet such requirements on a timely basis; and
- (3) For sources not in compliance with applicable requirements at the time of permit issuance, a schedule of remedial measures, including enforceable milestones, leading to compliance.

DNREC agrees with this comment and MAELC's regulatory interpretation. Items (1) and (2) of this three-part compliance schedule are already included in the permit under Condition 2.b. With respect to item number (3), a compliance schedule is only necessary for units that are not in compliance. To that end, DNREC notes that the facility's Title V permit application (Revision 8) had identified Boilers 1, 2 and 3 as not being in compliance and included compliance schedules for these units in the AQM 1001Z forms. However, DNREC does not believe that a compliance schedule is currently necessary for these units. See further explanation of this matter in a response to Premcor's comment requesting a compliance schedule (Premcor's General Comment 3). As noted in that response, Boilers 1 and 3 were shown to be in marginal non-compliance with their PM-10 emission limit. DNREC believes that these units can presently operate in compliance with good engineering operating practices and is requiring further testing for this purpose.

DNREC believes that a compliance schedule is typically necessary for units that require a significant effort to bring it into compliance. An example of when a compliance schedule would be necessary is for a unit which has repeatedly shown non-compliance and all efforts related to operating procedures and good air pollution control practices to bring the unit into compliance have failed. Such a unit would clearly require additional measures beyond good operating practices, perhaps in the form of additional controls, fuel changes, etc., which take time to implement. In this case, a compliance plan would be necessary wherein a schedule of remedial measures would be laid out along with enforceable milestones. DNREC does not believe that any unit covered by this Part 3 of the Title V permit meets these criteria for a compliance schedule.

<u>Comment</u>: Comment 2: Improved monitoring and recordkeeping requirements are needed.

<u>Response</u>: In this comment, MAELC indicates that the permit should require compliance stack testing for NOx, SO<sub>2</sub>, H<sub>2</sub>SO<sub>4</sub>, VOC and PM conducted under conditions of maximum process operations and throughputs and that these stack tests should be conducted not less than once every three years.

The compliance methods for the emission and operational limits in this permit include both stack testing and continuous emissions monitoring systems (CEMS), as well as parametric monitoring. Additionally, there are detailed reporting and recordkeeping requirements designed to document the information necessary for determining compliance with these limits. DNREC believes that these monitoring and recordkeeping requirements are reasonable and adequate for this purpose. In cases where stack tests are required, the testing is conducted using DNREC-approved methods and then only upon proper advance documentation and approval of the test protocol. In general, the stack tests are performed at or near maximum capacity operation, and the results of the stack tests are used to develop emission factors, e.g., in terms of lb/MMBtu, for the unit and pollutant in question. These emission factors can then be used to calculate emissions

based on actual operating parameters, e.g., actual amount of fuel burned or actual hours of operation. An example of such an emissions calculation is shown below.

$$tons/year = (lb/MMBtu) x (MMBtu/scf) x (scf/year) x (1 ton/2000 lbs)$$

This calculation shows that greater fuel use will result in greater emissions, and vice versa. Therefore, once an appropriate emissions factor is developed, emissions can be calculated in this manner for any operational level.

DNREC acknowledges that in order for an emission factor to be acceptable for use in determining compliance, it must be representative of current operating conditions of the unit in question. For this reason, DNREC agrees that the emission factors must be updated periodically by conducting new stack tests. In the proposed permit, a definition for the term "Stack Test Based Emissions Factor" has been included that specifies that these factors must be based on the most recent stack test results that are no more than five years old. This five-year period for stack tests coincides with the five-year term of the Title V permit. Therefore, the facility must perform new stack tests at least once within each permit term, which can then be used for compliance certification at the time of the next permit renewal.

<u>Comment</u>: Comment 3: The segmentation of the Title V permit is improper.

<u>Response</u>: In this comment, the MAELC argues that the segmentation of the facility's Title V permit into three parts is improper and that all applicable emission requirements at a facility must be contained in a single permit. MAELC also comments that they have long objected to DNREC's multi-segment permitting approach.

The Delaware City Refinery is a large, complex facility wherein many of the individual units qualify as major sources by themselves under the Title V regulations. The permitting of these units requires a considerable amount of DNREC's resources in order to ensure that all of the applicable requirements are identified and that the appropriate emission and operational limits, and the associated compliance, monitoring, reporting and recordkeeping requirements are specified. While preparing this permit, DNREC realized that if the permit was withheld until all of the units were processed, and all of the ongoing changes at the facility were adequately addressed (e.g., the repowering project), it would result in delaying the issuance of the permit for several additional years. Therefore, in order to expedite permit issuance, DNREC decided to issue the permit in three parts. With respect to MAELC's comment that they have long objected to this multi-segment permitting approach, DNREC notes that no objections were received from any party, including MAELC, at the time of the issuance of Part 1 of this permit in 2001.

It is important to point out that the three parts of the permit are not three separate permits; they have the same permit number and it is DNREC's intent to combine them into a single permit document once all parts have been finalized. At that time, all terms and conditions will be listed in a single document and the permit will have a single expiration date.

The MAELC has also commented that this segmentation of the permit creates opportunity for "gaps" in coverage, and argues that such gaps have occurred, especially in the case of Boiler 4. The MAELC points out that Boiler 4 has been excluded from the various emission limits in the permit and that this may be the result of the segmentation of the permit. With respect to the general comment about gaps in coverage, DNREC contends that no "gaps" have occurred and that every applicable requirement for each covered unit has been included in the Title V permit. Each part of this Title V permit is designed to cover all applicable requirements of the units included in that part without relying on the other parts of the permit to "fill in" the gaps. DNREC also contends that its objective is to include every unit at the facility that is subject to Title V in one or the other part of the permit, and then eventually include all units into a combined single permit document.

With respect to Boiler 4, DNREC acknowledges that this unit is not included in the emissions limits specified in the permit. This is not because a "gap" has occurred; instead, the reason is that Boiler 4 is a grandfathered unit under the Clean Air Act because it was constructed before the Clean Air Act was enacted. DNREC shares MAELC's concerns regarding the emissions from this unit and has duly noted the comment. As discussed in a separate response to a comment from the MAELC regarding capacity limits (MAELC General Comment 4), DNREC has decided to include the design capacity of Boiler 4 in the permit as an applicable requirement. While capacity limits cannot take the place of specific emission limits, they do provide some level of certainty in calculating emissions when combined with actual operating history of the units in question. For further discussion, see response below.

<u>Comment</u>: Comment 4: Failure to include capacity limits in the draft permit.

Response: In this comment, the MAELC raises a concern that the permit does not include boiler capacities, in terms of MMBtu/hour, as applicable requirements. The MAELC points out that boiler capacity is an essential part of the calculation of its potential to emit (PTE), and absent any limits on capacity, there is a potential for increased emissions by utilizing the unit at levels greater than rates represented in the application.

DNREC can only partially agree with MAELC's comment because Boiler 4 is the only unit in the draft permit that does not have pollutant specific emission limits derived from its potential to emit. All the emission limits for Boilers 1, 2 and 3 and the CCUs in the DNREC developed Regulation 2 permits for the Repowering Project were based on each emission unit's potential to emit. Additionally, DNREC had incorporated practically enforceable Regulation 2 permit limits for Boilers 1, 2 and 3 and the CCUs that when combined were lower than the emissions attributable to the PTE for each unit. This permitting strategy while affording the refinery a certain degree of operational flexibility (to meet its steam and power requirements) established emission limits that were considerably lower than the sum of each unit's PTE.

However, with respect to Boiler 4, DNREC shares MAELC's concern. Although, there are certain safeguards built into the permit to prevent occurrences of excess emissions by limiting the short term emissions in terms of lb/MMBtu, there are no mass emission limits specified on a ton per year basis for Boiler 4. This boiler was constructed prior to the enactment of the Clean Air Act and is therefore grandfathered under the Act. While DNREC is attempting to pursue further discussions with the facility, it prefers not to unilaterally impose numerical emission limits on this boiler. Currently, the only mechanism by which the emissions of this boiler can be quantified is by using its design capacity together with actual operating data such as fuel use and hours of operation. DNREC has therefore included the design capacity of Boiler 4, i.e., 737 MMBtu/hr, as an applicable requirement in the proposed permit. Note that this action translates into ton per year limits for Boiler 4 based on its maximum design capacity. It is DNREC's intent to eventually include tons-per-year limits for Boiler 4 based on its PTE.

# 4.0 Specific Comments from MAELC / Sierra Club as Provided During the Public Hearing on August 18, 2004

<u>Comment</u>: Comment 1) On page 20, item E states that "Except during periods of start up and shutdown, the burner steam injection and flue gas recirculation systems shall be working properly." Why do they NOT have to work properly during these times? Does this mean that there are deviations in terms of emissions standards that are allowed during start up/shut down? If so, why are they not specified? Do the manufacturer's recommended steam injection and flue gas recirculation (ii Compliance Meth. pg 19 Item D) rates somehow mandate this?

### Response:

Why do they NOT have to work properly during these times? During periods of startup and shutdown, the boiler is under transient operating conditions wherein it experiences large fluctuations in operating parameters. Until consistent steady-state operation is achieved, boiler performance is erratic. Injecting steam and recirculated flue gas into the boiler introduces additional variables that can affect reaching steady-state operation. Please note that even though operation is transient and at times erratic it is well controlled during startup and shutdown for safety reasons.

Does this mean that there are deviations in terms of emissions standards that are allowed during start up/shut down? If so, why are they not specified? Generally, achieving a certain specific performance criterion is not guaranteed during periods of startup and shutdown, and emission fluctuations (higher or lower) are expected during these periods. However, these are short-term emission fluctuations occurring over a period of a few hours. Furthermore, startup and shutdown of a boiler is not a routine operation and occurs very infrequently, typically for repair and maintenance purposes. Therefore, the net effect of startup and shutdown operations on normal annual emissions is minimal. Nonetheless, the emissions during startup and shutdown must be accounted for and included in the total annual emissions for compliance purposes. Deviations from the annual emission limits are not allowed.

Do the manufacturer's recommended steam injection and flue gas recirculation (ii Compliance Meth. pg 19 Item D) rates somehow mandate this? The manufacturer's recommended steam injection and flue gas recirculation rates apply during steady state operation of the boiler, and are not applicable during periods of startup and shutdown due to the transient operating conditions.

Comment: Comment 2) What are the revised capacity factors (Pg. 19 V. Reporting A) of Boilers 80-1 & 80-3 & EU 84-1 & 84-2? Use of Boiler 80-2 will increase after its modification & NOX and other pollutant emissions will decrease for the other above listed units. How is this reduction factored into this Title V permit? Will this permit need to be modified in terms of emissions standard for reduced capacity? For example on page 24 Section 4 SO2 emissions states SO2 levels of 3,827 TPY combined from EU 84-2 & 84-1 and 80-1, 80-2, 80-3. Is this based on levels from APC 90/0289? Does this exclude boiler 80-4? What will be the reduction of the 3,827 TPY once there is reduced

capacity? B. states that after modification boiler 80-2 can not emit SO2 in excess of 84.7 TPY. Why is the emission limit specified for 80-2 after modification, but not the others? The same questions for NOX, CO, VOC, Sulfuric Acid Mist & PM 10.

### Response:

What are the revised capacity factors (Pg. 19 V. Reporting A) of Boilers 80-1 & 80-3 & EU 84-1 & 84-2? The revised capacity factors will be developed by the facility based on revised utilization of Boilers 1 and 3 (EU 80-1 and 80-3) and the CCUs (EU 84-1 and 84-2). The utilization of these units is expected to reduce as Boiler 2 utilization increases. (Also see response to Comment 7 of Specific Comments from Premcor)

Use of Boiler 80-2 will increase after its modification & NOX and other pollutant emissions will decrease for the other above listed units. How is this reduction factored into this Title V permit? Will this permit need to be modified in terms of emissions standard for reduced capacity? DNREC concurs with the logic that utilization of Boiler 2 will increase since it was recently modified, which will result in decreased utilization of Boilers 1 and 3. The Title V permit (Part 3) contains emission limits as a combined total for Boilers 1, 2 and 3 and the combined cycle units (CCUs) that reflect the increased utilization of Boiler 2. In addition, the permit contains individual emission limits for Boiler 2 based on its planned greater utilization. The permit currently does not specify individual emission limits for Boilers 1 and 3 (EU 80-1 and 80-3) and the CCUs (EU 84-1 and 84-2) because these are currently in the process of being developed. Once the revised capacity factors for these units are developed, the permit will be modified to reflect the emissions of these individual units based on their expected lower utilization. (Also see response above and response to Comment 7 of Specific Comments from Premcor)

...on page 24 Section 4 SO2 emissions states SO2 levels of 3,827 TPY combined from EU 84-2 & 84-1 and 80-1, 80-2, 80-3. Is this based on levels from APC 90/0289? Does this exclude boiler 80-4? Yes, the 3827 TPY SO<sub>2</sub> emissions are based on Permit APC: 90/0289 and is a combined interim emission limit Boilers 1, 2 and 3. It does not include the SO<sub>2</sub> emissions from Boiler 4.

What will be the reduction of the 3,827 TPY once there is reduced capacity? The facility is currently in the process of developing the reduced capacity factors for Boilers 1 and 3 and the CCUs. A reduction is anticipated as discussed in the above responses to this comment and once developed, the total SO<sub>2</sub> emission limit of 3,827 tpy will be adjusted accordingly.

B. states that after modification boiler 80-2 can not emit SO2 in excess of 84.7 TPY. Why is the emission limit specified for 80-2 after modification, but not the others? The same questions for NOX, CO, VOC, Sulfuric Acid Mist & PM 10. The Title V permit requires the facility to submit a permit application proposing the individual limits for Boilers 1 and 3 and the CCUs. Although these individual emission limits were required to have been prepared by now, there have been startup problems with the repowering project that have prevented sustained operation. The facility has requested an extension until

March 31, 2005 to submit these limits. DNREC finds this request for an extension to be reasonable. Once developed, these limits will be included in the Title V permit.

<u>Comment</u>: Comment 3) Page 25 NOX and CO emissions monitoring-iii. Compliance Method. A mandates compliance with CEMS. B states that "Compliance with a less stringent (higher) emission limit shall be based on compliance with a more stringent limit." What exactly does B. mean? This statement is vague and contradictory.

Response: The purpose of this condition is to simply point out that if more than one emission limit applies, e.g., a NOx limit of 0.20 lb/MMBtu from the Regulation No. 2 permit and 0.25 lb/MMBtu from Regulation No. 12, Section 3.2(a), then compliance with the more stringent (i.e., lower) limit of 0.20 lb/MMBtu would automatically mean compliance with the 0.25 lb/MMBtu limit.

Comment: Comment 4) Pg. 31 & 32. There is mention of an Acid Rain Permit for Boiler 4-phase II permit application dated 3/2/00. Has this been approved? 11. i.A.1 states that each affected source and unit at the affected source shall submit a complete Acid Rain permit application. What exactly are the other Affected Sources & Units here? Are they boilers 80-1, 80-2, 80-3 and EU84-1 & 84-2? If so, will this change the emissions stipulated for these units for SOX and NOX? If there is no existing permit for Boiler 4, just an application submitted 3/2/00, then are SOX and NOX being monitored for Boiler 4?

### Response:

Pg. 31 & 32. There is mention of an Acid Rain Permit for Boiler 4-phase II permit application dated 3/2/00. Has this been approved? The facility has applied for an Acid Rain Permit pursuant to the U.S. EPA Acid Rain Program that is under review.

11. i.A.1 states that each affected source and unit at the affected source shall submit a complete Acid Rain permit application. What exactly are the other Affected Sources & Units here? Are they boilers 80-1, 80-2, 80-3 and EU84-1 & 84-2? If so, will this change the emissions stipulated for these units for SOX and NOX? The language included in the Title V permit has been taken directly from the regulation. The only unit at the facility subject to the Acid Rain program is Boiler 4. Other units are not affected units as defined by this program and their permitted emission limits are not affected.

If there is no existing permit for Boiler 4, just an application submitted 3/2/00, then are SOX and NOX being monitored for Boiler 4? The pollutants regulated under the Acid Rain Program are SO<sub>2</sub> and NOx, and their emissions from Boiler 4 are monitored. The emissions of SO<sub>2</sub> are monitored to determine whether sufficient allowances are available within the units compliance subaccount, and the NOx emissions are monitored pursuant to the NOx RACT program.

<u>Comment</u>: Comment 5) How does the NOX limit of .2 lb/mmBtu (rolling 24 hr average) relate to the NOX emissions granted under the Acid Rain permit for boiler 4? Is this limit in addition to or included in the limits specified in the Boiler 4 Acid Rain permit?

Ref. E page 26. Also how do the NOX emission under the Acid Rain permit factor into the NOX allowance deductions under permit AQM 003/00016-1 and Regulation 39 section 2(a)?

### Response:

How does the NOX limit of .2 lb/mmBtu (rolling 24 hr average) relate to the NOX emissions granted under the Acid Rain permit for boiler 4? Is this limit in addition to or included in the limits specified in the Boiler 4 Acid Rain permit? NOx emissions are limited in accordance with specific regulations and by the type of fuel combusted. The NOx RACT (Regulation 12) emission limit 0.20 lb/MMBtu applies for gas combustion. Boiler 4 is allowed to burn low sulfur No. 2 oil during periods of natural gas curtailment. During oil combustion, the NOx RACT limit of 0.25 lb/MMBtu applies (also see response above and response to Comment 12 of Specific Comments from Premcor). In either case, these limits cannot be directly compared to the acid rain program because it does not specify lb/MMBtu limits for NOx for gas and oil combustion. Only coal-fired units are covered under the NOx portion of the acid rain program. For example, for a dry-bottom wall-fired boiler (i.e., a unit like Boiler 4), the current NOx limit for coal combustion is 0.46 lb/MMBtu under the acid rain program. However, as mentioned above, this limit cannot be directly compared with the 0.20 or 0.25 lb/MMBtu NOx RACT limits for Boiler 4 because these limits apply to different fuels.

Also how do the NOX emission under the Acid Rain permit factor into the NOX allowance deductions under permit AQM 003/00016-1 and Regulation 39 section 2(a)? The NOx Budget Trading Program (Permit Number AQM 003/00016-I and Regulation No. 39, Section 2(a)) is not related to the Acid Rain Program. While both programs have been designed to reduce overall NOx emissions, there are key differences in these programs. For example, the Acid Rain Program specifies a short term NOx emissions limit (in terms of lb/MMBtu) that cannot be exceeded, while the NOx Budget Trading Program is a cap-and-trade program which specifies that the unit must hold sufficient allowances in its account (or acquire such allowances by trading) to cover the actual tons of NOx emitted during the ozone season (May through September). The acid rain program only applies to Boiler 4 at the facility, while several units at the facility (including all four boilers) are subject to the NOx Budget Trading Program. The facility is required to comply with both programs independently of each other

<u>Comment</u>: Comment 6) Why are there are no CO, PM 10, VOC & Sulfuric Acid Mist emissions limits for Boiler 4?

<u>Response</u>: The Boiler 4 does not have these limits because it is a grandfathered unit under the Clean Air Act. However, in order to provide some level of certainty in estimating emissions from this unit, DNREC is including the boiler's design capacity as an applicable requirement in the permit. Please see further discussion in a response under "General Comments from MAELC."

<u>Comment</u>: Comment 7) Why are there no lead emissions specified for boilers 80-2 and 80-4 on page 30?

<u>Response</u>: Boiler 2 burns gas (refinery fuel gas and natural gas), which is a clean burning fuel. Test results for this boiler have not detected any lead emissions. Therefore, no lead emission limit is included in the permit. For Boiler 4, see response above.

<u>Comment</u>: Comment 8) Why are there no fugitive emissions standards specified for the four boilers and the combined cycle gas turbines?

<u>Response</u>: The boilers and the CCUs at the facility are not considered to be in VOC service. Therefore, they are not subject to 40 CFR 60 Subpart VV requirements.

<u>Comment</u>: Comment 9) The DNREC technical memo references insignificant activities that per Title V do not need to be included in the emissions but do need to be mentioned in the permit. However, we cannot locate these insignificant activities anywhere in either document. What activities are included? Where are these activities covered in the draft permit?

Response: DNREC thanks the commenter for pointing out this discrepancy in the review memorandum. The memorandum has been revised to remove the reference to insignificant activities. Appendix "A" of Regulation 30 lists all the insignificant activities. The Company's application listed the activities defined in Appendix "A" under 2 categories, i.e., "Group 1" insignificant activities by specific activity type such as air conditioning systems, lawn mowers, welding equipment etc. and "Group 2" insignificant activities that include emission units for which an applicable requirement has not yet been promulgated, are not elsewhere listed as insignificant activities and which have the potential to emit in the aggregate the following air contaminants at less than the specified rates:

V	OC	25 TPY in New Castle or Kent Counties or 50 TPY in Sussex
County		
Pa	rticulate	40 TPY
PN	<i>I</i> I-10	15 TPY
SC	$\mathbf{O}_2$	40 TPY
NO	$O_{x}$	25 TPY in New Castle or Kent Counties or 100 TPY in Sussex
County		

DNREC had addressed the "Group 1" insignificant activities in the technical memorandum accompanying Part 1 of this Title V permit issued in 2001. In this memorandum DNREC had also indicated that the "Group 2" insignificant activities would be addressed upon completion of the subsequent part of the Title V permit. DNREC intends including the "Group 2" insignificant activities when Part 2 of the permit is completed.

### 5.0 Comments from U.S. EPA

<u>Comment</u>: After discussion with Ravi Rangan I now understand now where to look when the permit refers to "See "Conditions Applicable to Multiple Pollutants in this Table" but I think that this is unclear to the reader as written. To make it clearer I suggest the following wording - "See Conditions Applicable to Multiple Pollutants in this Table - Emission Unit 80, 82, 83 and 84 were appropriate or mention the subparagraph for each. Please explain or correct the permit.

<u>Response</u>: The proposed permit identifies the applicable Emissions Unit ID when referring to "Conditions Applicable to Multiple Pollutants in this Table."

<u>Comment</u>: Condition 3 Table 1, Emission Unit 82 paragraph (b)(1)(i) refers to 40 CFR 60, Subpart VV under the record keeping and reporting requirements in addition to what is listed in the permit should ther permit also indicated that the facility need to do record keeping and reporting according to 40 CFR 60, Subpart VV. Please explain or correct the permit.

<u>Response</u>: DNREC agrees. The permit has been revised to indicate that the recordkeeping and reporting must be performed in accordance with the requirements of 40 CFR 60 Subpart VV and Delaware Regulation No. 24, Section 29.

<u>Comment</u>: Under Condition 3 Table 1(b)(1)(i)(A) the permit indicated the 40 CFR 60, Subpart VV but this is not indicated on the checklist. Please correct.

<u>Response</u>: The checklist is a list of applicable regulations prepared by DNREC to facilitate EPA's review of the draft permit. The checklist has been updated to indicate the applicability of 40 CFR 60 Subpart VV.

<u>Comment</u>: Under Condition 3 Table 1(d)(1)(ii) the acronym LSDF should be spelled out when using for the first time in the permit, i.e., Low Sulfur Diesel Fuel (LSDF). Please explain or correct.

<u>Response</u>: DNREC concurs. LSDF has been spelled out in the proposed permit where it is used for the first time.

<u>Comment</u>: Under Condition 3 Table l(e)(2) Odor - since odor is enforced by the State only, the permit should indicated that Odor is State Enforceable Only.

<u>Response</u>: The odor requirement is indeed enforced by the State only. The draft permit identified this requirement as State Enforceable Only.

### 6.0 Comments from Green Delaware

<u>Comment</u>: What are the total emissions from the facility?

<u>Response</u>: The estimate of the total emissions from the facility, based on the most recent emissions inventory are for the year 2002 which are presented in the table below. The Department anticipates receiving the inventory figures for 2003 by the end of October 2004. The facility is required to submit annual emissions inventories, which are available for review at DNREC's Air Quality Management Offices at New Castle and Dover.

Pollutant	2002 Emissions (tons/year)	Average Emissions, 1994- 2002 (tons/year)
SO2	34,096	40,378
CO	3,857	8,490
NO2	3,533	5,461
TSP	1,602	1,811
PM10	1,193	1,348
VOC	665	1,245

<u>Comment</u>: What are the consequences of these air pollutant emissions?

Response: As part of the permitting of the repowering project, the facility had performed a dispersion modeling analysis to calculate cumulative impacts from all sources at the facility. The modeling was performed in accordance with the State and Federal guidelines and was designed to calculate the maximum pollutant impacts in areas surrounding the facility. The modeling analysis demonstrated compliance with the applicable primary and secondary National Ambient Air Quality Standards, thereby indicating that the impacts were within acceptable levels and not detrimental to public health and the environment.

<u>Comment</u>: Incorporating Sierra Club's comments by reference.

Response: Please see responses to Sierra Club's comments elsewhere in this document.

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pc: Dover Title V File Bruce Steltzer